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David H. Meyer
Acting Deputy Director
Office of Electricity Delivery and Energy Reliability, TD-1
U.S. Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

Via email: Economic.Dispatch@hq.doe.gov

Re: Energy Policy Act of 2005, Section 1234 Economic Dispatch Study

Dear Mr. Meyer:

Thank you for this opportunity to contribute to the study regarding the benefits of economic dispatch in the electricity industry.

Ameren Corporation, a Fortune 500 company based in the city of St. Louis, Missouri, was created with the December, 1997 merger of Union Electric Company and CIPSCO Incorporated, parent of Central Illinois Public Service Company (based in Springfield, Illinois). Union Electric is now doing business as AmerenUE; Central Illinois Public Service Company is now doing business as AmerenCIPS. Ameren expanded with the 2003 addition of Central Illinois Light Company, now doing business as AmerenCILCO (based in Peoria, Illinois), and the recently acquired Illinois Power Company, now doing business as AmerenIP (based in Decatur, Illinois). With more than $17 billion in total assets, Ameren, through its subsidiaries, has a net generating capacity of more than 15,200 megawatts (MW) and provides energy services to approximately 2.3 million electric customers and more than 900,000 natural gas customers across 64,000 square miles of service territory in Illinois and Missouri.

The following are Ameren Corporation's responses:

Q1) What are the procedures now used in your region for economic dispatch? Who is performing the dispatch (a utility, an ISO or RTO, or other) and over how large an area (geographic scope, MW load, MW generation resources, number of retail customers within the dispatch area)?

The Ameren companies are participants in the Midwest ISO energy market, which uses a Security Constrained Economic Dispatch (SCED). SCED utilizes the generation availability and offer price parameters input by the generators participating in the market, which includes both utility and non-utility generators. SCED attempts to perform a least cost dispatch taking into account transmission system characteristics and limitations. SCED relies on the manual activation of congestion management for transmission lines that are experiencing normal or contingency overloads. The Midwest ISO dispatches generation resources across a footprint that is just under one million square miles and contains approximately 135,000 MW of generation capacity.

Q 2) Is the Act's definition of economic dispatch (see above) appropriate? Over what geographic scale or area should economic dispatch be practiced? Besides cost and reliability, are there any other factors or considerations that should be considered in economic dispatch, and why?

The definition of Economic Dispatch (ED), as given, is appropriate in the simplest terms. A more full-bodied definition would include the economical utilization of the right mix of resources to meet changing system conditions and requirements, in its entirety, (generation, transmission, ancillary services, and customer demand) at any point in time, over a given electrical system in a reliable manner.

ED decisions also take into consideration unit specific operating parameters, such as the amount of time necessary to start a unit, the minimum loading of a unit, fuel availability, maximum run time, environmental restrictions, etc. In addition, ED decisions must take into account the unique operating and availability characteristics of hydro, wind and solar generation where these resources exist.

Another important consideration regarding ED decisions to be taken into account is the reliability of the transmission system. Least cost generation dispatch is limited by acceptable loadings on the transmission system. Failure to consider such limitations can seriously jeopardize reliability.

Cost and reliability should be the driving factors in any dispatch scenario. One limiting factor to the size of a dispatch area is the necessity of recognizing the subtle reliability complexities that may not be captured in current state-of-the-art SCEDs. The larger the area across which economic dispatch is performed, the larger the opportunity for a more optimal economic dispatch, but at the same time the management of system reliability becomes more complex. The larger the set of generating units involved in the ED solution, the more complicated the logistic issues become for the system operator, thus demanding a higher level of automation and coordination. Specific areas of concern would be transient and voltage stability, reliability must run generation, and operating reserve issues. These reliability issues presently must be analyzed and identified prior to real-time operation or in parallel with operation to augment or expand any future ED.

Q 3.) How do economic dispatch procedures differ for different classes of generation, including utility-owned versus non-utility generation? Do actual operational practices differ from the formal procedures required under tariff or federal or state rules, or from the economic dispatch definition above? If there is a difference, please indicate what the difference is, how often this occurs, and its impacts upon non-utility generation and upon *retail electricity users. If you have specific analyses or studies that document your position, please provide them.*

A) Different classes of units have different characteristics (ramp rate speed, minimum/maximum load levels, startup/shutdown times, ability to cycle unit, heat rate, fuel type, fuel flexibility, etc), and these differences are incorporated into determining the optimal economic dispatch. As an example, utilities may use less efficient simple-cycle combustion turbines during periods of peak demand due to the quick start and high ramp rate characteristics of these units. All of these differences are taken into account when making dispatch and unit commitment decisions.

There is no difference in the Midwest ISO market on economic dispatch of utility versus non-utility owned units. Both groups have the ability to offer their generation resources into the market, and the market selects the optimal economic dispatch of the units based solely on the offer information and the existing system reliability requirements. Generally, in non-organized markets, a NUG would become part of the economic dispatch only if it is a designated network resource or if its output is covered by a contract for dispatch in a merit order economic dispatch. Barring these conditions, a NUG would only be dispatched around the parameters of a bi-lateral transaction with a counter-party.

B) In the Midwest ISO LMP Market, operational practices do not significantly differ from formal procedures. Where there is a difference, it is generally due to the market's immaturity and the need for the formal procedure to have more detail and clarification, for example, the use of quick start units to handle dynamic changes in operational conditions.

Q 4) What changes in economic dispatch procedures would lead to more non-utility generator dispatch? If you think that changes are needed to current economic dispatch procedures in your area to better enable economic dispatch participation by non-utility generators, please explain the changes you recommend.

In the Midwest ISO, no changes are necessary to increase NUG dispatch. Midwest ISO rules allow both utility and non-utility generation acting as network and energy resources to participate on an equal basis in the energy market.

Q 5) If economic dispatch causes greater dispatch and use of non-utility generation, what effects might this have – on the grid, on the mix of energy and capacity available to retail customers, to energy prices and costs, to environmental emissions, or other impacts? How would this affect retail customers in particular states or nationwide?
If you have specific analyses to support your position, please provide them to us.

Assuming a completely robust transmission system, the effects of ED on the operation of the grid should not be significant. If the transmission system is constrained, however, reliability issues will be of concern and an ED algorithm would need to recognize the earlier mentioned reliability issues. Bottlenecks to the movement of energy may also emerge if there is a great disparity in the production costs between areas or classes of generation. If ED would result in large changes in generation dispatch and area interchange as compared to earlier planning and operating assumptions, then these changes would need be reflected in operations and planning models to understand their potential impacts. Going forward, the planning of the transmission system may need to change to sustain the anticipated economic operation. For instance, the existing transmission grid in some parts of the Midwest ISO footprint was not designed assuming a wide-area economic dispatch. Transmission system reinforcements could be required in these areas to make the system more robust to accommodate the ED and maintain system reliability.

Since the transmission system is not constraint free and was not designed for large area economic dispatch, widespread application of ED could require increased transmission investment. The potential impact on retail customers would be higher costs for transmission, possibly offset by lower energy costs. Depending on where the transmission is needed and the allocation of those costs, it is possible that cost shifting would also occur. Given the existing stock of generators and the current demand for energy, a new ED process could result in retail customers in some states saving money at the expense of those in other states.

Certainly to the extent that ED resulted in lower cost coal fired generation displacing gas and oil generation, certain environmental emissions could increase (e.g. SO_2 and NO_x).

Q 6) Could there be any implications for grid reliability – positive or negative – from greater use of economic dispatch? If so, how should economic dispatch be modified or enhanced to protect reliability?

It is unlikely that a modified economic dispatch would enhance reliability. The installed generation, the transmission system configuration and the load do not change due to an expansion of the economic dispatch footprint. Most generation interconnected to the transmission system can be called upon today to address reliability issues like voltage problems or stability issues. Use of ED over larger geographic area could actually result in fewer units being committed to run on a given day, thus reducing available operating reserves and negatively impacting reliability.

In the short term, strict use of economic dispatch, which reduces the use of higher-cost generation, could reveal transmission system limitations resulting from certain higher-priced units not being dispatched. As discussed above, greater use of economic dispatch ultimately should include in the merit order algorithm a reflection of steady state, transient, stability, regulation, and reserve requirements in order to not degrade reliability. This is a step beyond the existing N-1 SCED criteria present in today's markets. If dispatching were to occur on a limited transmission criteria basis or, worse yet, on an economic cost basis only, transmission facilities would likely become overloaded and unreliable operation would occur as large amounts of power would transfer from lower cost regions of the country to higher cost regions.

Respectfully submitted,

Maureen A. Borkowski

Maureen A. Borkowski
Vice President, Transmission
PO Box 66149 MC 630
Saint Louis, MO 63166-6149

CC: Alison Silverstein alisonsilverstein@mac.com
Joe Eto jheto@lbl.gov